Interstate Natural Gas Association of America

June 13, 2003

Air and Radiation Docket
Attention Docket Number OAR-2002-0053
U.S. Environmental Protection Agency
1301 Constitution Avenue, NW, Room B-108
Washington, DC 20460

Dear Sir or Madam:

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, submits these comments on the U.S. EPA's "Standards of Performance for Stationary Gas Turbines" (Turbine NSPS), issued as a proposal and direct final rule on April 14, 2003, 68 FR 18003 and 17990. On May 28, 2003, EPA published notice in the Federal Register withdrawing the direct final rule (68 FR 31611) as a result of adverse comments and extension of the comment period to June 13, 2003.

INGAA member companies transport more than 90 percent of the nation's natural gas, through some 180,000 miles of interstate natural gas pipelines. Our industry operates more than 1,000 natural gas-fired combustion turbines in the United States, including more than 400 units that are subject to the New Source Performance Standards (NSPS) for stationary gas turbines, under 40 CFR 60, Subpart GG. These NSPS units are diffusion flame turbines and lean premix turbines – very few of the turbines use water or steam injection.

In the preamble to the proposed rule for the Turbine NSPS, EPA indicates that the rules are meant to codify alternative testing and monitoring procedures that have been routinely approved by EPA. INGAA supports EPA's efforts to streamline the NSPS requirements and remove burdensome requirements. Specifically, we support the Agency's proposal to remove requirements to monitor sulfur and nitrogen content for natural gas. INGAA also supports EPA's proposal to make correction of emissions to ISO conditions optional for lean premix turbines. INGAA encourages EPA to move forward quickly with these non-controversial aspects of the rulemaking.

INGAA finds that the Agency's proposal and direct final rule would, however, wrongly impose new requirements with regard to compliance monitoring for nitrogen oxides (NOx) for those turbines that do not use water injection control technology. Our comments address the following specific issues:

1. The proposed Turbine NSPS revisions would wrongly impose significant new requirements for ongoing NOx compliance monitoring on turbines in natural gas transmission. This outcome is in direct conflict with EPA's stated intent to simply codify existing requirements, rather than impose new ones.

2. The proposed provisions in 60.334(c), which address monitoring to determine excess NOx emissions for "existing"[1] NSPS turbines, should be revised to clearly state that monitoring requirements included in existing permits should not be revised as a result of this rulemaking.
3. The proposed provisions in 60.334(e), which address use of a continuous emissions monitoring system (CEMS) to determine excess NOx emissions for "new"[2] NSPS turbines, should be revised so they do not impose CEMS requirements on owner/operators that are not otherwise required to use CEMS.
4. The proposed provisions in 60.334(f), which address the use of continuous parameter monitoring as an alternative to CEMS for "new" NSPS turbines, should be revised so they do not impose continuous parameter monitoring requirements on owner/operators that are not otherwise required to perform such monitoring.
5. The proposed provisions in 60.334(g), which address the use of performance test data to establish acceptable parameter ranges, should be revised to provide the opportunity for owner/operators to establish and/or adjust operating parameter limitations based on performance tests, engineering analysis, design specifications, manufacturer recommendations or other applicable information, such as a performance test on a similar unit.
6. EPA should not attempt to rely on the Agency's 1994 memorandum regarding compliance monitoring for turbines that use technology other than water injection as the basis for the proposed Turbine NSPS revisions. Rather, the 1994 memorandum should be formally withdrawn by the Agency.

INGAA expects that EPA proposed the NOx compliance monitoring revisions to explicitly allow the use of continuous monitoring for the Turbine NSPS when such monitoring is already required due to other regulatory requirements, such as Part 75. INGAA does not oppose the Agency providing the option for Part 75 sources to use Part 75 monitoring to demonstrate compliance with the Turbine NSPS. We recommend that EPA revise the final rulemaking to effect the Agency's original intent of codifying the option to use continuous monitoring, when such monitoring is required for other reasons, such as Part 75. The final rulemaking should not impose significant new requirements on other owner/operators. If EPA intends to impose new monitoring requirements for NSPS turbines, EPA should issue a new proposal with that intent expressly stated. Such a proposal should include the full range of compliance monitoring for natural gas turbines, as currently approved by EPA in existing permits for NSPS turbines. We recommend that this be done in conjunction with the revision of the NSPS emission standards, which we understand the Agency is undertaking shortly.

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[1] 60.334(c) addresses turbines that commenced construction, reconstruction or modification after October 3, 1977, but before May 29, 2003. These turbines will be referred to as "existing" NSPS turbines in these comments.

[2] 60.334(e) addresses turbines that commence construction on or after May 29, 2003. These turbines will be referred to as "new" NSPS turbines in these comments.

We note that EPA's justification for the content of the proposed rule is partially based on the Agency's 1994 memorandum regarding compliance monitoring for turbines that use technology other than water injection. This memorandum wrongly attempts to establish new regulatory requirements through guidance, rather than the regulatory process. Moreover, Agency decisions since 1994 concerning turbines in natural gas transmission service have uniformly ignored this memorandum. The memorandum is also inconsistent with Agency permitting decisions on NSPS turbines under Title V. INGAA recommends that EPA not attempt to justify its current actions on the content of this policy memorandum which the Agency has effectively ignored in its decisions for the past 9 years. Indeed, we recommend that EPA issue a memorandum to explicitly withdraw the 1994 memorandum.

In addition, although it is not specifically addressed in this rulemaking, we encourage EPA to clarify the regulations regarding the use of turbine component replacement for routine turbine overhauls to state that these routine component replacements do not trigger NSPS applicability.

INGAA appreciates the opportunity to comment on this rulemaking. If you have any questions, please feel free to contact us at 202-216-5935.

Sincerely,

Lisa S. Beal

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cc: Jaime Pagan, U.S. EPA, Combustion Group, Emission Standards Division (C439-01), USEPA Mailroom, Research Triangle Park, NC 27711

Attachments

COMMENTS ON THE
STANDARDS OF PERFORMANCE FOR
STATIONARY GAS TURBINES
PROPOSED RULE AND DIRECT FINAL RULE
68 Federal Register 18003 and 17990, April 14, 2003
40 CFR 60, Subpart GG

Submitted by:
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202-216-5935

Submitted to:
Docket ID No. OAR-2002-0053
Air and Radiation Docket
Attention Docket Number OAR-2002-0053
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1301 Constitution Avenue, NW, Room B-108
Washington, DC 20460

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1. List of permits provided to EPA on May 21, 2003
2. Example Part 71 permit

1. The proposed Turbine NSPS revisions would wrongly impose significant new requirements for ongoing NOx compliance monitoring on turbines in natural gas transmission. This outcome is in direct conflict with EPA's stated intent to simply codify existing requirements, rather than impose new ones.

EPA stated in the direct final and proposed Turbine NSPS revision that the intent of the rule was to codify existing requirements:

> The amendments will codify several alternative testing and monitoring procedures that have routinely been approved by EPA. (68 FR 17990 and 18003)

Although the Agency's intended result may be achieved for turbines in the electric utility industry that are subject to Part 75, INGAA's review of the rule indicates that the proposed revisions would actually impose significant new requirements on the natural gas transmission industry. We note that the proposed NOx compliance monitoring provisions are oriented to electric utility turbines, subject to Part 75 and ignore other gas turbine users, such as our industry. In fact, the Docket materials refer almost exclusively to information related to the electric utility industry (see Item II-B-1, a memorandum that addresses the projection of stationary gas turbines and the impacts of the Turbine NSPS revision as an example). Also, in the preamble, EPA refers frequently to turbines subject to Part 75. Insufficient information was gathered related to the existing NOx monitoring requirements for turbines in other industries.

The only documents included in the Docket that are relevant to NOx compliance monitoring for turbines in the natural gas transmission industry are two e-mails provided as attachments to Docket Item II-B-1. These e-mails highlight the fact that turbines in natural gas transmission service are not conducting continuous monitoring for the Turbine NSPS. The e-mail attachment from EPA Region VII indicates that CEMS are not typically installed for compressor station turbines: ". . . these compressor turbines do not have NOx CEMS and use the techniques in Subpart GG to determine compliance." In addition, an e-mail from Solar Turbines provided as another attachment to Docket Item II-B-1 indicates that CEMS are very uncommon for Solar turbines (1-14 MW) unless add-on controls are required, such as SCR. These small Solar turbines represent the size class that is used most often in the natural gas transmission industry. Therefore, as shown by these Docket items, the proposed Turbine NSPS revision would impose significant additional requirements on our industry.

The content of these documents was ignored in the economic analysis that is presented as Item II-B-1 and EPA included no costs for the significant new requirements that would be imposed by the proposed revisions. Therefore, EPA has failed to estimate the true impacts of the rulemaking, including the impacts related to increased monitoring, recordkeeping and reporting requirements for our industry. In addition, EPA has not considered the current Agency-approved NOx compliance monitoring techniques that are used by our industry for NSPS turbines as alternatives to the continuous monitoring provisions included in Part 75.

INGAA member companies operate over 415 turbines in the United States that are subject to the Turbine NSPS, 40 CFR 60, Subpart GG. As shown in Table 1, these turbines are located in 41 states. Only one unit has been identified with water injection. Approximately 200 of the turbines are lean premix turbines. The remaining turbines are diffusion flame turbines with no additional NOx controls.

In response to this rulemaking, INGAA member companies have gathered over 100 permits, including construction and Title V permits, for turbines subject to the NSPS (see Table 1). Thirteen examples of these permits were provided to Mr. Jaime Pagan on May 21, 2003 (see Attachment 1). In addition, we are providing with these comments an example Part 71 permit issued by EPA, which was not available on May 21, 2003 (see Attachment 2). Additional permits can be provided at EPA's request. The following types of monitoring were identified in the permits:

- One-time NOx stack test
- Stack test every 2.5 years or every 5 years (once or twice in permit term)
- Annual stack test / NOx portable test
- Semi-annual NOx portable test
- Quarterly NOx portable test
- Parameter monitoring

As shown in Table 2, nearly half of the permits include only a one-time NOx stack test. In general for natural gas transmission sources, no ongoing NOx emissions or parameter monitoring has been required for the Turbine NSPS in preconstruction permits [state minor New Source Review (NSR) and Prevention of Significant Deterioration (PSD)] because Subpart GG specifies ongoing NOx monitoring requirements only for turbines using water injection technology. NSPS turbines in our industry are subject to the one-time NOx performance test requirements. Ongoing NOx monitoring requirements have been required for NSPS turbines in the following instances:

- NSPS turbines also subject to Title V periodic monitoring;
- NSPS turbines also subject to NOx RACT; or
- NSPS turbines also subject to more restrictive NOx emission limitations under state minor NSR or PSD.

Even when monitoring is required in the permits collected, it is less stringent than the monitoring proposed by EPA for the Turbine NSPS revision. As noted above, many permits include only a one-time performance test, in accordance with Subpart GG. In addition, we note that even when ongoing compliance monitoring has been required for other underlying requirements, continuous monitoring of emissions or parameters has not typically been required. In our industry CEMS have been required on four turbines that use Selective Catalytic Reduction (SCR). Parameter monitoring systems (with various rates of recording from continuous to daily) have been required on very few units (12 of the 160 reviewed) and many of these have accepted parameter monitoring to demonstrate compliance with emission limitations such as 25 ppm NOx, which are much lower than the Turbine NSPS limitation. For the proposed NSPS revision, EPA did not consider the full range of compliance monitoring that is in practice for industries not subject to Part 75, such as natural gas transmission. In addition, the Agency clearly has not made a determination that existing monitoring requirements, less stringent than Part 75, are insufficient to ensure compliance with the NSPS emission limitation. On the contrary, based on the Agency's review and approval of the existing permits that contain these compliance monitoring provisions, the Agency has agreed that the monitoring meets the requirements of Title V and periodic monitoring to ensure compliance with the underlying applicable requirements.

We recommend that EPA revise the final rulemaking to effect the Agency's original intent of codifying the option to use continuous NOx or parameter monitoring when such monitoring is required for other reasons, such as Part 75, without imposing new requirements on other owner/operators. In addition, INGAA recommends that EPA formally withdraw the 1994 policy memorandum (discussed further in Comment #6) regarding compliance monitoring for turbines that use technology other than water injection. Finally, if EPA intends in the future to impose new monitoring requirements for NSPS turbines, we recommend that EPA issue a new proposal with that intent expressly stated. Such a proposal should include the full range of compliance monitoring for natural gas turbines, as currently approved by EPA in existing permits for NSPS turbines, and should consider the emission characteristics of the turbines and control technologies relative to the NSPS emission limitation to judge the necessity and merit of each monitoring option. We recommend that this be coordinated with the revision of the NSPS emission standard for gas turbines, which we understand the Agency is undertaking shortly.

Table 1. Turbines in Natural Gas Transmission Covered by the Turbine NSPS			
State	**NSPS Turbines**	**Turbines Covered by Permits Collected**	**Permits Collected**
LA	40	13	4
TX	34	34	19
WY	30	12	8
PA	27	30	10
AL	18		
AZ	17	7	5
NM	17	1	1
KS	16	12	6
CO	15	10	5
WA	15	4	2
NY	14	9	4
TN	14	4	1
OK	13		
OR	12		
UT	12	6	3
ID	11		
IL	9	6	4
KY	9	9	6
MA	9	1	1
MI	9	7	4
MN	9		
OH	8	9	3
MS	7		
VA	7	18	4
WI	6	3	3
FL	5	5	1
GA	5	5	2
AR	3	2	2
CA	3		
IA	3	2	1
IN	3	5	2
MT	3		
NJ	2		
RI	2	1	
WV	2	2	2
MO	1		
NC	1		
ND	1		
NE	1		
NV	1		
SC	1		
AK	0	8	4
Part 71		4	2
TOTAL	**415**	**215**	**105**

Table 2. Types of NOx Monitoring Identified in Existing Permits for NSPS Turbines in Natural Gas Transmission Service

Type of Monitoring	Total Number of Turbines*	Percentage of Total*
One-Time NOx Stack Test	78	49%
Stack Test Every 2.5 or 5 Years (Once or Twice in Permit Term)	19	12%
Annual Stack Test/Portable	27	17%
Semi-Annual Portable Test	15	9%
Quarterly Portable Test	9	5%
Parameter Monitoring	12	8%
TOTAL	160	100%

*Permits for 160 turbines subject to NSPS were reviewed. We are also aware of four turbines equipped with SCR that have NOx CEMS.

2. The proposed provisions in 60.334(c), which address monitoring to determine excess NOx emissions for "existing" NSPS turbines, should be revised to clearly state that monitoring requirements included in existing permits should not be revised as a result of this rulemaking.

INGAA opposes the provisions proposed in 60.334(c). That paragraph addresses monitoring for existing NSPS turbines that do not use steam or water injection to control NOx emissions. The proposed regulatory language presents two options to determine compliance with the NSPS NOx emission limitation:

- Owner/operator "may" use CEMS.
- Owner/operator "may" continue with an alternative procedure of continuously monitoring compliance under EPA approval of a petition for such alternative monitoring.

This proposed regulatory language fails to address existing turbines in natural gas transmission service that are subject to the NSPS. The vast majority of these NSPS turbines neither have CEMS, nor an EPA-approved petition for alternative monitoring. EPA and permitting authorities already have had the opportunity to review the monitoring provisions contained in these permits – through preconstruction and Title V permit reviews. It is also noteworthy that existing NSPS turbines may be subject to NOx emission limitations that are significantly lower than the NSPS standard, as a result of preconstruction permitting or NOx RACT. As part of the proposed Subpart GG revisions, EPA should explicitly state that owner/operators of an existing NSPS turbine may continue to employ monitoring requirements (if any) outlined in existing preconstruction, state operating, or Title V permits. EPA also should make clear that permitting authorities are not required to revisit or revise monitoring requirements in existing permits as a result of the Turbine NSPS revisions. Lacking this clarification, INGAA is concerned about possible revisions to current monitoring requirements in existing preconstruction, Title V, and state operating permits. INGAA is opposed to any such reopening of permits for existing NSPS turbines.

INGAA expects that EPA has proposed the revisions in 60.334(c) to explicitly allow CEMS for turbines that already require CEMS due to other regulatory requirements, such as Part 75. However, the revisions fail to address turbines in other industries, such as natural gas transmission, that are not currently subject to CEMS requirements. The revisions also fail to explicitly state that these Turbine NSPS revisions should not result in revisions of existing permits for NSPS turbines. Therefore, INGAA requests that EPA revise 60.334(c) in the final rulemaking to clearly state that monitoring requirements included in existing permits should not be revised as a result of this rulemaking.

3. The proposed provisions in 60.334(e), which address the use of CEMS to determine excess NOx emissions for "new" NSPS turbines, should be revised so they do not impose CEMS requirements on owner/operators that are not otherwise required to use CEMS.

INGAA does not support the proposed provisions in 60.334(e). That paragraph addresses monitoring for new NSPS turbines that do not use steam or water injection to control NOx emissions. The proposed regulatory language indicates that the owner/operator "may" use a CEMS, or may use the alternative described in paragraph (f) (discussed in Comment #4). INGAA expects that EPA proposed the revisions in 60.334(e) to explicitly allow the use of CEMS for turbines that already require CEMS due to other regulatory requirements. INGAA does not oppose the Agency's goal of allowing owner/operators the flexibility to use data from a CEMS already required for other reasons to demonstrate compliance with the Turbine NSPS.

However, INGAA does oppose the fact that the proposed revision to the Turbine NSPS would impose significant new regulatory requirements on new NSPS turbines in natural gas transmission service. Recent installations of NSPS turbines in natural gas transmission service have not required the use of CEMS. INGAA believes that paragraphs (e) and (f) collectively would result in the imposition of new and costly monitoring requirements for new NSPS turbines in natural gas transmission. Therefore, we find the proposed revision of 60.334(e) to be inconsistent with EPA's statements that the proposed revisions will impose no new regulatory requirements. We also note that EPA has failed to account for the impacts of these new regulatory requirements on our industry (see Docket Item II-B-1).

We recommend that EPA revise these provisions in the final rulemaking to effect the Agency's original intent of codifying the option to use continuous monitoring, when otherwise required for other reasons, such as Part 75, without imposing significant new requirements on other owner/operators. We also recommend that EPA explicitly state in the preamble that permitting authorities, under Title V periodic monitoring or other programs, are not restricted to CEMS and may continue to consider the full range of compliance monitoring options for gas-fired turbines. As discussed further in Comment #6, INGAA does not agree that the 1994 policy memorandum regarding compliance monitoring for turbines that use technology other than water injection establishes regulatory requirements for continuous monitoring for NSPS turbines. If EPA intends in the future to impose new monitoring requirements for NSPS turbines, we recommend that EPA issue a new proposal with that intent expressly stated. Such a proposal should include the full range of compliance monitoring for natural gas turbines, as currently approved by EPA in existing permits for NSPS turbines and should be coordinated with the revision of the NSPS emission limitations. In any case, INGAA opposes mandatory CEMS for new NSPS turbines, under the existing NSPS, based on the following:

a. CEMS are not required typically for NSPS turbines in natural gas transmission service – in contrast to turbines in electrical generation where CEMS are common. Even in electrical generation, turbines used for peaking service do not typically use CEMS.

b. New turbines in natural gas transmission service typically are permitted at emission levels much lower than the current NSPS emission limitation. For example, new lean premix turbines are typically guaranteed at 25 ppm NOx, when the NSPS emission limitation for the same unit would be 150 ppm NOx or higher.

It should be noted that even with emission limitations dramatically lower than the current NSPS, new turbines in natural gas transmission service are not typically required to install CEMS.

c. New lean premix turbines have little possibility of exceeding the NSPS emission limitation. Manufacturers typically guarantee very low NOx emissions for new lean premix turbines. For example, in general, for our size range, turbine manufacturers typically guarantee 25 ppm NOx for new lean premix turbines. For retrofit applications, manufacturers typically guarantee 42 ppm NOx for turbines in our size range. These guarantees typically only apply over a load range of approximately 50 to 100 percent of rated horsepower. However, even at lower loads, these turbines have little possibility of exceeding the applicable NSPS emission limitations. As an example, the emission database for the Turbine MACT standard includes an emission test (Test Id. 314) for a Solar Mars turbine equipped with lean premix technology (SoLoNOx) at 100%, 75%, 50% and 35% load. The test at 35% of rated horsepower is outside the nominal window for SoLoNOx operation, but NOx emissions are reported as 30 ppm. Therefore the turbine has little probability of exceeding the NSPS emission limitation. Therefore, a mandatory CEMS requirement is not appropriate and imposes an unreasonable regulatory burden.

d. Most new NSPS turbines typically used in natural gas transmission service are lean premix turbines. However, some models are diffusion flame, such as turbines in the Solar Saturn family and the Allison 501KC. These are small turbines. For example, the Solar Saturn is rated approximately 1200 horsepower or approximately 11 MMBTU/hr. Solar only offers the Saturn as a diffusion flame turbine and there is no lean premix technology available for this small turbine. The Solar guarantee for the Saturn is 100 ppm NOx, while the NSPS emission limitation is 150 ppm NOx. A mandatory CEMS requirement for these small diffusion flame turbines is not appropriate and imposes an unreasonable regulatory burden.

4. The proposed provisions in 60.334(f), which address the use of continuous parameter monitoring as an alternative to CEMS for "new" NSPS turbines, should be revised so they do not impose continuous parameter monitoring requirements on owner/operators that are not otherwise required to perform such monitoring.

INGAA does not support the proposed provisions in 60.334(f). That paragraph addresses continuous parameter monitoring as an alternative to CEMS for new NSPS turbines that do not use steam or water injection to control NOx emissions. For new diffusion flame turbines without SCR controls, the proposed provision would require that owner/operators develop a predictive emission monitoring system (PEMS) to include at least four parameters "indicative of the unit's NOx formation characteristics." For new lean premix turbines, the proposed provision would require that owner/operators monitor operating parameters to "determine whether the unit is operating in the lean premixed (low-NOx) combustion mode."

Like the proposed provisions in 60.334(e), INGAA expects that EPA proposed the revisions to 60.334(e) to explicitly allow the use of continuous parameter monitoring for turbines that already require such monitoring due to other regulatory requirements, such as Part 75. INGAA does not oppose the Agency's goal of allowing owner/operators the flexibility to use data from continuous parameter monitoring to demonstrate compliance with the Turbine NSPS when such monitoring is already required for other reasons. However, we note that the proposed requirements are actually more stringent, especially in terms of averaging times and exceedances, than the parameter monitoring options provided under Part 75.

INGAA does oppose the fact that, like the proposed requirement for CEMS, this provision would impose significant new regulatory requirements on new NSPS turbines in natural gas transmission service. Most recent installations of NSPS turbines in natural gas transmission service have not required the use of continuous parameter monitoring, as proposed for the NSPS revisions. INGAA believes that paragraphs (e) and (f) collectively would result in the imposition of new and costly monitoring requirements for new NSPS turbines in natural gas transmission. Therefore, we find the proposed revision of 60.334(e) to be inconsistent with EPA's statements in the direct final rule and the proposed rule that the proposed revisions will impose no new regulatory requirements. We also note that EPA has failed to account for the impacts of these new regulatory requirements on our industry (see Docket Item II-B-1).

We recommend that EPA revise these provisions in the final rulemaking to effect the Agency's original intent of codifying the option to use continuous parameter monitoring, when otherwise required for other reasons, such as Part 75, without imposing significant new requirements on other owner/operators. We also recommend that EPA explicitly state in the preamble that permitting authorities, under Title V periodic monitoring or other programs, are not restricted to continuous monitoring of emissions or parameters and may continue to consider the full range of compliance monitoring options for gas-fired turbines. As discussed further in Comment #6, INGAA does not agree that the 1994 policy memorandum regarding compliance monitoring for turbines that use technology other than water injection establishes regulatory requirements for continuous monitoring for NSPS turbines in our industry. If EPA intends in the future to impose new monitoring requirements for NSPS turbines, we recommend that EPA issue a new proposal with that intent expressly stated. Such a proposal should include the full range of compliance monitoring for natural gas turbines, as currently approved by EPA in existing permits for NSPS turbines. In any case, INGAA opposes mandatory requirements for continuous monitoring of operating parameters, as proposed, based on the following:

a. Continuous parameter monitoring is not consistent with monitoring typically required for NSPS turbines in natural gas transmission service. Again, this is in contrast to turbines in electrical generation, which may be conducting continuous parameter monitoring to comply with Part 75, as referenced in the proposed revisions to the Turbine NSPS.

b. As stated above, new lean premix turbines have little possibility of exceeding the NSPS emission limitation. Indeed, verification of lean premix combustion, as proposed for the Turbine NSPS, ensures NOx emissions at levels far below the current NSPS emission limitations. Equally, information about operation outside of lean premix mode does not provide meaningful information about whether a unit has failed to comply with the current NSPS emission limitations, as shown by the low NOx emissions reported at 35% load for the Solar Mars unit (Test Id. 314.4), discussed above.

c. Continuous parameter monitoring is not appropriate for new diffusion flame turbines subject to the NSPS. As stated above, some models of diffusion flame turbines are installed for natural gas transmission service, such as the Solar Saturn and the Allison 501KC. There is no PEMS available at present for these diffusion flame turbines. Therefore, an owner/operator would have to develop a PEMS, which would impose an unreasonable cost burden.

5. The proposed provisions in 60.334(g), which address the use of performance test data to establish acceptable parameter ranges, should be revised to provide the opportunity for owner/operators to establish and/or adjust operating parameter limitations based on performance tests, engineering analysis, design specifications, manufacturer recommendations or other applicable information, such as a performance test on a similar unit.

The proposed provisions in 60.334(g) would require that operating parameters be established based on performance testing alone.[3] This provision should be revised to allow owner/operators the opportunity to establish more appropriate parameter ranges, based on performance testing, engineering analysis, design specifications, manufacturer recommendations or other applicable information, such as a performance test on a similar unit. In other rulemakings, EPA typically has allowed owner/operators flexibility in establishing acceptable operating parameter ranges. In fact, EPA precedent in a recent MACT has included provisions that allow the operator the ability to adjust operating parameter limits established in the initial performance test using alternatives including engineering analysis. In the Petroleum Refinery MACT for catalytic cracking units (CCUs), 40 CFR 63.1571(d)(4) states:

> "…if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters… from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information."

Clearly this provision is provided to acknowledge that it may not be possible to achieve worst-case operation during the performance test. The final Turbine NSPS should include similar language to recognize the difficulty in conducting the performance test at specific conditions and to provide owner/operators the same flexibility granted to operators of affected sources in other recent rulemakings. In addition, this flexibility would allow owner/operators to use advances in parameter monitoring that may be achieved through future research programs.

For operators of turbines in gas compression service on the natural gas pipeline system, it is especially important for the final rule to specify that tests on a similar turbine are adequate to demonstrate the range of acceptable operating parameters. We note that EPA has recognized the potential to use data from similar units to demonstrate performance in approving the use of data from a performance test on a similar unit to satisfy the performance test requirements for another unit subject to the Turbine NSPS (see Applicability Determination Index Control Number 9800061). Our industry's turbines operate in load-following applications, and the pipeline conditions may preclude operation at specific load conditions, e.g., turbines may not be able to operate at specific load conditions at the predetermined time scheduled for a performance test to establish minimum and maximum limits. The flexibility of allowing the testing of a similar unit to serve as the basis for establishing acceptable operating parameters for other similar units will prevent this requirement from imposing an undue burden on specific turbines due to the limitations of their operating environment.

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[3] As noted in Comment #4 above, INGAA opposes the proposed requirements to impose additional requirements for continuous parameter monitoring for new NSPS turbines. However, INGAA does not oppose EPA providing the option for owner/operators to use parameter monitoring to demonstrate compliance with the NSPS emission limitation for NOx, if the owner/operators are already conducting parameter monitoring for other reasons, such as Part 75.

6. EPA should not attempt to rely on the Agency's 1994 memorandum regarding compliance monitoring for turbines that use technology other than water injection as the basis for the proposed Turbine NSPS revisions. Rather, the 1994 memorandum should be formally withdrawn by the Agency.

Docket item II-B-2 includes a one-page memorandum from the EPA Applicability Determinations Index (ADI) dated May 31, 1994 (Control Number 9700124) that address alternative control techniques and monitoring for the Turbine NSPS. EPA staff has indicated that the 1994 memorandum represents Agency policy that continuous monitoring is required for NSPS turbines equipped with control technology other than water injection. The full text of the one-page memorandum states:

> I have recently received inquiries about using alternative technologies and monitoring methods to control NOx emissions from NSPS Subpart GA-regulated gas turbines. Subpart GG provides a standard of performance for gas turbines, based on using water injection technology, and describes a corresponding continuous water-to-fuel ratio NOx monitoring method. I understand that some turbines are using NOx control methods other than water injection and some of the Regional Offices have asked what type of monitoring approaches, if any, should be required for those control technologies since Subpart GG does not address this issue directly.
>
> The Stationary Source Compliance Division (SSCD), in cooperation with other OAQPS staff, has determined that the mandate of section 111 of the Clean Air Act was to continuously reduce NOx emissions from gas turbines (a major source of emissions) and the intent of Subpart GG was to continuously monitor that emission reduction. Therefore, if a Subpart GG facility uses a control technology other than water injection (including Selective Catalytic Reduction, Selective Non-Catalytic Reduction, and Dry Low NOx Combustor) this facility should propose a compatible continuous alternative NOx monitoring method.
>
> If you have any question, please call Zofia Kosim, of my staff at 703-308-8733.

INGAA opposes the Agency relying on this one-page memorandum as the basis for the proposed Turbine NSPS revisions and recommends that the Agency formally withdraw the memorandum, for the following reasons:

a. The 1994 memorandum attempts to establish regulatory requirements through guidance rather than the regulatory process.

b. The 1994 memorandum has largely not been implemented through Agency decisions since 1994 and is inconsistent with Agency decisions on compliance monitoring for NSPS turbines under preconstruction and Title V permitting.

c. In the addition of compliance monitoring through Title V periodic monitoring, EPA has acknowledged that no ongoing NOx monitoring is required per the Turbine NSPS.

d. The 1994 memorandum fails to recognize the distinction between turbines that use add-on controls and lean premix turbines that achieve lower emissions through inherent process design.

Each of these issues is discussed further below.

a. <u>The 1994 memorandum attempts to establish regulatory requirements through guidance rather than the regulatory process.</u>

As noted in the 1994 memorandum, Subpart GG does not impose ongoing NOx compliance monitoring requirements for turbines equipped with control technologies other than water injection. The 1994 memorandum attempts to establish regulatory requirements for turbines that rely on other technologies through Agency guidance, rather than the regulatory process. INGAA finds this approach to be inconsistent with the requirement that the Agency issue notice and request comment on all actions that establish regulatory requirements. The fact that an agency cannot escape notice and comment requirements by labeling a major addition to a rule as a mere interpretation was noted in the D.C. Circuit ruling in 2000 against the Agency's Periodic Monitoring Guidance (Appalachian Power Company v. EPA, D.C. Cir. April 14, 2000). It is also noteworthy here that in their review of the Agency's Periodic Monitoring Guidance, the court noted that, "test methods and the frequency of testing for compliance with emissions limitations are surely 'substantive' requirements; they impose duties and obligations on those who are regulated."

The 1994 memorandum is a clear instance of the Agency attempting to impose substantive new monitoring requirements through the guise of interpreting the existing Subpart GG regulation. The requirement to provide notice and comment on substantive rulemakings is necessary to give the regulated community notice and to provide the agency an opportunity to consider the perspectives and interests of those affected by the rule. As shown by the D.C. Circuit ruling, Agency action that does not follow these requirements cannot establish substantive requirements.

b. <u>The 1994 memorandum largely has not been implemented through Agency decisions since 1994 and is inconsistent with Agency decisions on compliance monitoring for NSPS turbines under preconstruction and Title V permitting.</u>

As shown in Comment #1 above, the 1994 memorandum has not been recognized or implemented in permit actions for NSPS turbines in natural gas transmission service. Of the 400 NSPS turbines in natural gas transmission service, less than 5 percent have any ongoing parameter monitoring requirements. Most of the turbines are subject either to the one-time NOx performance test, as specified under Subpart GG, or periodic testing requirements that stem from underlying construction permits (state minor NSR or PSD) or Title V periodic monitoring requirements. EPA routinely reviews these construction and Title V permits. In addition, EPA itself has failed to acknowledge and implement the 1994 memorandum when they have issued Part 71 permits (see Attachment 2). Therefore, we find that the 1994 memorandum does not represent Agency policy with regard to the required compliance monitoring for turbines subject to Subpart GG.

c. In the addition of compliance monitoring through Title V periodic monitoring, EPA has acknowledged that no ongoing NOx monitoring is required per the Turbine NSPS.

As discussed in Comment #1 above, some NSPS turbines have been subject to periodic monitoring requirements under Title V to address the lack of ongoing NOx monitoring requirements under Subpart GG. For example, in the support document for the attached Part 71 permit, the EPA Region notes that periodic monitoring is added because the monitoring requirements in Subpart GG only require a one-time performance test for NOx to show initial compliance (see Attachment 2).

In accordance with the D.C. Circuit decision in 2000, permitting authorities may consider additional monitoring requirements only when the standard requires "no periodic testing, specifies no frequency, or requires only a one-time test." The fact that periodic monitoring has been added for NSPS turbines subject to Title V underscores the fact that Subpart GG provides no authority for ongoing compliance monitoring for turbines that do not use water injection.

d. The 1994 memorandum fails to recognize the distinction between turbines that use add-on controls and lean premix turbines that achieve lower emissions through inherent process design.

The 1994 memorandum is a one-page statement that since continuous monitoring is required for units that use water injection, continuous monitoring should also be required for units that use other technologies, such as Dry Low NOx Combustion, also known as lean premix technology. The memorandum does not provide any data to support the determination that continuous monitoring is appropriate for these other technologies. In fact, the memorandum fails to recognize the difference between units that rely on add-on controls, such as water injection, and units that rely on inherent process design, like lean premix technology. In the case of water injection, continuous monitoring of operating parameters may be appropriate because of the capability of the owner/operator to adjust the rate of water injection and thereby significantly affect NOx emissions. In addition, for water injection, the control technology parameters can be monitored cost effectively and are indicative of emissions performance. In the case of lean premix technology, continuous monitoring of operating parameters is not necessary to ensure compliance with the NOx emission limitation under the Turbine NSPS. As discussed in Comment #3 above, NOx emissions from lean premix turbines are significantly lower than the current Turbine NSPS standard. In addition, lean premix technology is not an add-on control technology that can be adjusted or "turned-off" by the owner/operator – the turbine is operated by the manufacturer's control logic, which cannot be manipulated by the owner/operator to engage or disengage the lean premix technology.

ATTACHMENT 1

Permits Provided to EPA on May 21, 2003				
State	**Company**	**Type of Permit**	**Permit Number**	**Type of Monitoring**
IL	Midwestern Gas Transmission	Construction Permit	1987800ABV	One-Time Test
Iowa	Northern Natural Gas	Title V Permit	01-TV-016	One-Time Test
KY	General Permit	Title V Permit	G-97-001	One-Time Test
TX	General Permit	Title V General Permit	(None)	One-Time Test
NY	Tennessee Gas Pipeline	Title V Permit	8-2452-00008/00007	Test Every 5 Years
OH	CNG Transmission	Title V Permit	17-10-00-0101	Test Every 2.5 Years
PA	Columbia Gas Transmission	Title V Permit	01-05003	Annual Portable Test
RI	Tennessee Gas Pipeline	Construction Permit	1608	Annual Stack Test
AK	Alyeska Pipeline Service Co.	Title V Permit	072TVP01	One-Time Test, or Annual Stack Test if >90% of Limit
PA	Tennessee Gas Pipeline	Title V Permit	58-00001	Semi-Annual Portable Test
TX	El Paso Natural Gas	Title V General Permit	O-00502	Quarterly Portables
WY	Kern River Gas Transmission	Title V Permit	30-008	Parameter Monitoring

ATTACHMENT 2

Part 71 Permit, V-OU-0003-00.00, Effective Date: March 19, 2001

Statement of Basis, January 24, 2001

United States Environmental Protection Agency
Region VIII
Air and Radiation Program
999 18th Street, Suite 300
Denver, Colorado 80202-2466

AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

Permit Number: V-OU-0003-00.00
Replaces Permit No.: none

Issue Date: February 7, 2001
Effective Date: March 19, 2001
Expiration Date: March 19, 2006

In accordance with the provisions of title V of the Clean Air Act and 40 CFR part 71 and applicable rules and regulations,

Colorado Interstate Gas- Natural Buttes Compressor Station

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the permit conditions listed in this permit.

This source is authorized to operate in the following location(s):

Uintah and Ouray Indian Reservation
SW 1/4, Section 24, T9S, R21E in Uintah County, Utah

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. All terms and conditions of the permit are enforceable by EPA and citizens under the Clean Air Act.

The permit number cited above should be referenced in future correspondence regarding this facility.

Patricia D. Hull
for
Jack W. McGraw
Acting Regional Administrator
US EPA Region VIII

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Abbreviations and Acronyms

AR	Acid Rain
ARP	Acid Rain Program
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
EIP	Economic Incentives Programs
EPA	Environmental Protection Agency
gal	gallon
HAP	Hazardous Air Pollutant
hr	hour
Id. No.	Identification Number
kg	kilogram
lb	pound
MACT	Maximum Achievable Control Technology
MVAC	Motor Vehicle Air Conditioner.
Mg	megagram
mmBtu	million British Thermal Units
mo	month
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOX	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
PM	Particulate Matter
PM10	Particulate matter less than 10 microns in diameter
ppm	parts per million
PSD	Prevention of Significant Deterioration

PTE	Potential to Emit
psia	pounds per square inch absolute
RMP	Risk Management Plan
SNAP	Significant New Alternatives Program
SO2	Sulfur Dioxide
tpy	Ton Per Year
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

TABLES

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I. Source Identification and Unit-Specific Information

I.A. General Source Information

Parent Company name: Colorado Interstate Gas Company

Parent Company Mailing Address: P.O. Box 1087
Colorado Springs, Colorado 80944

Plant Name: Natural Buttes Compressor Station

Plant Mailing Address: 1176 East 1500 South
Vernal, Utah 84078

Plant Location: SW 1/4, Section 24, T9S, R21E in Uintah County

Region: VIII	**State:** Utah	**County:** Uintah
Reservation:	Uintah & Ouray	**Tribe:** Ute
Company Contact:	Barry Schatz	**Phone:** 719-520-4281
Plant Manager/Contact:		**Phone:**
Responsible Official:	William D. Stevens	**Phone:** 719-473-2300
Tribal Contact:	Elaine Willie	**Phone:** 435-722-3941
Local Government Contact: N/A		**Phone:** N/A

SIC Codes (4 digit, if available): 4922, 1321

AFS Plant Identification Number:

Other Clean Air Act Permits: No other Federal Clean Air Act Permits

Description of Process: The Natural Buttes Compressor Station removes natural gas liquids (NGL's) from the wet gas stream the plant receives from production operations. Natural gas enters the facility from gathering lines and is fed to slug catchers to remove liquids. Collected liquids are stored in pressure vessels, and the remaining gas is fed to compressors driven by gas fired turbines. Natural gas discharged by the compressors is fed to an ethylene glycol dehydration unit. Ethyl glycol is introduced to the gas stream, which subsequently is chilled and fed to a three-phase separator. The compressors driven by natural gas fired reciprocating engines are utilized to provide propane refrigeration to cool the natural gas stream. Residue natural gas exiting the three-phase separator is transported off-site to a sales line, NGL collected from the three-phase separator is stored in pressure vessels, and rich ethylene glycol is sent to a regenerator. Heat is applied indirectly via heat medium oil to the regenerator to volatilize water from the rich glycol.

The potential to emit for the facility as a whole is as follows:

NOx = 433 tpy; VOC = 177 tpy; SO2 = 0 tpy; PM10 = 0 tpy; CO = 318 tpy; lead = 0 tpy
Total HAP = 34 tpy - Formaldehyde is the HAP emitted in the greatest amount at 14 tpy.

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Total HAP = 34 tpy - Formaldehyde is the HAP emitted in the greatest amount at 14 tpy.

I.B. Source Emission Points

Table 1. Source Emission Points

The following table identifies and describes each emissions unit, such as process units and control devices, and each alternative operating scenario later referenced in this permit.

Emission Unit Id.	Description	1. Installation Date 2. Maximum design heat input 3. Fuel type 4. Use	Control Equipment
CG01, CG02	2 - Superior 8G825 Engines Serial Nos. 292039, 292029	1. October, 1982 2. 5.8 Million Btu/hr each 3. Natural Gas 4. Compressor Driver	None
CG04, CG05, CG06, CG07	4 - Allison 501-KC5 Gas Turbines Serial Nos. ASP-1477, ASP-1471, ASP-1464, ASP-1467	1. November, 1992 2. 35.4 Million Btu/hr each 3. Natural Gas 4. Compressor Driver	None
EG1, EG2, EG3	3 - Caterpillar 3512 LE Engines Serial Nos. 4KC00323, 4KC00324, 4KC00326	1. November, 1992 2. 6.1 Million Btu/hr each 3. Natural Gas 4. Electric Generator Driver	None
H1	Heatec Hot Oil Heater	1. 2000 2. 6.67 Million Btu/hr 3. Natural Gas 4. Process Heater	None
T8365	Propak Custom Skid Dehydration Unit Still	1. November, 1992 2. N/A 3. Natural Gas 4. Ethylene Glycol Regeneration	Condenser
T17	300 barrel atmospheric storage tank	1. December, 1992 2. N/A 3. N/A 4. Pigging liquids storage/loadout	None
Fug	Piping components	1. 1981-1992 2. N/A 3. N/A 4. Fugitive Equipment Leaks (Plant-Wide)	None

Table 2. Insignificant Emission Points

The following table identifies and describes the insignificant activities/emission units at the source.

Emission Unit Id. No.	Description
1	T1 - 240 bbl. triethylene glycol storage tank
2	T2 - 240 bbl. Methanol storage tank
3	T3 - 6,875 gallon lubricating oil storage tank
4	T5 - 250 bbl. Unleaded gasoline storage tank
5	T7 - 1250 gallon septic tank
6	T10 - 7140 gallon slop tank
7	T11 - 1250 gallon septic tank
8	T12 - 700 gallon Ambitrol storage tank
9	T13 - 700 gallon lubricating oil storage tank
10	T14 - 700 gallon used oil storage tank
11	T15 - 700 gallon ethylene glycol storage tank
12	T16 - 100 gallon lubricating oil day tank
13	T18 - 6300 gallon used oil storage tank
14	500 gallon diesel storage tank
15	1200 gallon Ambitrol storage tank
16	V19 - Blowdown vessel vent
17	T8 - Water tank
18	T6 - Abandoned water tank
19	V1, V2, V3, V4 - Pressure vessels

II. Requirements for Specific Units

The specific units as listed below are subject to, but not limited to, the following emission standards, requirements, and provisions. Any emission standards, requirements, or provisions that apply to specific units that are replaced under the Alternative Operating Scenarios provisions listed in II.B. below, shall also apply to the replacement units.

II.A. Emission Standards [40 CFR § 71.6(a)(1), § 71.6(a)(1)(i) and § 71.6(a)(1)(iii)]

(a) The emission standards (from NSPS subpart GG) listed in the table below apply to units CG4, CG5, CG6, and CG7.

Pollutant	Emission Standard	Regulatory Reference
Nitrogen oxides	$STD = 0.0150\frac{(14.4)}{Y} + F = 172$ ppm where Y= 12.52 kilojoules per watt hour and F = 0 for units CG4, CG5, CG6, CG7 and STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis)	40 CFR 60.332 (a)(2)
Sulfur dioxide	Fuel sulfur content shall not exceed 0.8 percent by weight	40 CFR 60.333 (b)

(b) The permittee shall meet the following requirements of 40 CFR part 60, subpart KKK (and the requirements of 40 CFR part 60, subpart VV as required by subpart KKK) as they apply to the natural gas processing plant at this facility:

(i) The permittee shall comply with the standards specified in 40 CFR §60.632 with exceptions as specified in 40 CFR §60.333.

(c) The permittee shall meet the following requirements of 40 CFR part 63, subpart HH as they apply to the natural gas processing plant at this facility by the compliance dates specified in 40 CFR §63.760(f):

(i) The permittee shall comply with the standards specified in 40 CFR §63.764(c) with exceptions as specified in 40 CFR §63.764(e).

(ii) The permittee shall comply with the requirements specified in 40 CFR §63.760(g)(1).

II.B. Alternative Operating Scenarios [40 CFR § 71.6(a)(9) and 40 CFR § 71.6(a)(3)(ii)]

(a) Replacement of an existing permitted engine or turbine with a new or overhauled engine or turbine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine or turbine being replaced, and which satisfies all the provisions for Off-Permit Change under this permit, including the provisions specific to engine or turbine replacement, shall be considered an allowed alternative operating scenario under this permit.

(b) The permittee shall also keep records of the maintenance activities performed at the source and make them available for review. Such records should be sufficient to establish the level of maintenance performed and may be maintained at either the field location or at the permittee's nearest regularly manned facility. These records will be maintained for a period of at least five (5) years from the date of the engine or turbine replacement.

II.C. Monitoring and Testing Requirements [40 CFR § 71.6(a)(3)(i)(A) through (C)]

(a) The permittee shall comply with the requirements of 40 CFR §60.334(b)(2) (from NSPS subpart GG) for monitoring of sulfur content and nitrogen content of the fuel being burned in units CG4, CG5, CG6, and CG7. For sulfur dioxide and nitrogen oxides, the custom fuel sampling schedule as approved by letter dated October 23, 2000, and listed below, shall be followed.

(i) Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

(ii) Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The approved reference methods are : ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2). The Gas Processors Association (GPA) test method entitled "Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes" (GPA Standard 2377-86) is an approved alternative method.

(iii) Sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

(iv) If after the monitoring required in item (iii) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(v) Should any sulfur analysis as required in items (iii) or (iv) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Environmental Protection Agency Region VIII of such excess emissions and the custom schedule shall be re-examined by the EPA. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(vi) Stationary gas turbines that use the same supply of pipeline quality natural gas to fuel multiple gas turbines may monitor the fuel sulfur content at a single common location.

(vii) Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be made available for inspection.

(viii) Approval of this custom fuel monitoring schedule is contingent on the following conditions. The stationary gas turbines shall: (1) only be fired with pipeline quality natural gas; (2) not be fired with an emergency fuel; and (3) not be supplied its fuel from an intermediate bulk storage tank.

(b) The permittee shall measure NOx emissions from emission units CG4, CG5, CG6, and CG7 at least once every quarter, to show compliance with the requirements of 40 CFR 60.332 (a)(2). To meet this requirement, the permittee shall measure the NOx emissions from each turbine using a portable analyzer and the monitoring protocols approved by EPA. The permittee shall submit the analyzer specifications and monitoring protocol to EPA for approval within sixty (60) calendar days of the effective date of this permit. Such monitoring shall begin in the first calendar quarter following EPA notification to the applicant of the approval of the monitoring protocol.

(c) The permittee shall sample and analyze the inlet gas in accordance with Method 18 of 40 CFR part 60, appendix A in order to demonstrate that compressor engines CG1 through CG7, and all ancillary equipment, are not being operated in volatile hazardous air pollutant (VHAP) service. The sampling and analysis of the inlet gas shall begin in the first calendar quarter following the effective date of this permit, and shall be conducted semiannually for one year. After one year, if the analysis continues to show that the equipment is not being operated in VHAP service, the sampling and analysis shall be conducted annually.

(d) The permittee shall comply with the monitoring requirements specified in §§63.774 and 63.775 (from NESHAP subpart HH).

II.D. <u>Recordkeeping Requirements</u> [40 CFR §71.6(a)(3)(ii), 40 CFR §60.7(b), §60.7(f), and §60.116b(a) and (b), and 40 CFR §63.10(b)(3)]

(a) The permittee shall comply with the following recordkeeping requirements:

(i) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(ii) The permittee shall maintain a file of all measurements, including performance testing measurements, monitoring device calibration checks, and other information required by the NSPS conditions of this permit.

(b) The permittee shall keep records of all required emission monitoring required in Section II.B.(b) of this permit. The records shall include the following:

(i) The date, place, and time of sampling or measurements;

(ii) The date(s) analyses were performed;

(iii) The company or entity that performed the analyses;

(iv) The analytical techniques or methods used;

(v) The results of such analyses; and

(vi) The operating conditions as existing at the time of sampling or measurement.

(c) The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(d) The permittee shall keep readily accessible records showing the dimension of storage vessel T17 and an analysis showing the capacity of storage vessel T17. This record and analysis shall be kept for the life of the source.

(e) The permittee shall comply with the recordkeeping requirements of 40 CFR §60.635 (from NSPS subpart KKK).

(f) The permittee shall comply with the recordkeeping requirements of §63.774 (from NESHAP subpart HH).

(g) Recordkeeping requirement for applicability determinations. If an owner or operator determines that his or her stationary source that emits (or has the potential to emit, without considering controls) one or more hazardous air pollutants is not subject to a relevant standard or other requirement established under this part, the owner or operator shall keep a record of the applicability determination on site at the source for a period of 5 years after the determination, or until the source changes its operations to become an affected source, whichever comes first. The record of the applicability determination shall include an analysis (or other information) that demonstrates why the owner or operator believes the source is unaffected (e.g., because the source is an area source). The analysis (or other information) shall be sufficiently detailed to allow the Administrator to make a finding about the source's applicability status with regard to the relevant standard or other requirement. If relevant, the analysis shall be performed in accordance with requirements established in subparts of this part for this purpose for particular categories of stationary sources. If relevant, the analysis should be performed in accordance with EPA guidance materials published to assist sources in making applicability determinations under section 112, if any.

II.E. Reporting Requirements [40 CFR §71.6(a)(3)(iii).]

(a) The permittee shall submit to EPA reports of any required monitoring under this permit semi-annually by April 1 and October 1. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Section IV.F.(a) of this permit.

(i) "Deviation," means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or recordkeeping established in accordance with § 71.6(a)(3)(i) and (a)(3)(ii). For a situation lasting more than 24 hours which constitutes a deviation, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

(1) A situation where emissions exceed an emission limitation or standard;

(2) A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or

(4) A situation in which an exceedance or an excursion, as defined in 40 CFR part 64 occurs.

(b) The permittee shall promptly report to the EPA Regional Office deviations from permit requirements, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. "Prompt" is defined as follows:

(i) Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit;

(ii) Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(1) For emissions of a hazardous air pollutant or a toxic air pollutant(as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence.

(2) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours.

(3) For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report required in paragraph (a) of this section.

(c) If any of the conditions in (b)(ii)(1) - (3) are met, the source must notify EPA by telephone or facsimile based on the timetables listed above. A written notice, certified consistent with Section IV.F.(a) of this permit must be submitted within 10 working days of the occurrence. All deviations reported under this section must also be identified in the 6-month report required under paragraph (a) of this section.

(d) The permittee shall comply with the reporting requirements of 40 CFR §60.636 (from NSPS subpart KKK).

(e) The permittee shall comply with the reporting requirements of 40 CFR §63.775 (from NESHAP subpart HH).

II.F. General Provisions of NSPS [See 40 CFR part 60]

(a) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(b) This source is subject to all applicable sections of 40 CFR, part 60, subpart A, including, but not limited to, the following sections:

Section	Description
60.1	Applicability
60.2	Definitions
60.3	Units and abbreviations
60.4(a)	Address
60.5	Determination of construction or modification
60.6	Review of plans
60.7	Notification and record keeping
60.8	Performance tests
60.9	Availability of information
60.11	Compliance with standards and maintenance requirements
60.12	Circumvention
60.14	Modification
60.15	Reconstruction
60.17	Incorporations by reference
60.19	General notification and reporting requirements

II.G. General Provisions of NESHAP [See 40 CFR part 63]

(a) This source is subject to the requirements of 40 CFR part 63, subpart A as outlined in Table 2 to subpart HH.

II.H. Compliance Schedule and Progress Reports [40 CFR §71.6(c)(3) and §71.5(c)(8)(iii)]

(a) For applicable requirements with which the source is in compliance, the source will continue to comply with such requirements.

(b) For applicable requirements that will become effective during the permit term, the source will meet such requirements on a timely basis.

III. Facility-Wide or Generic Permit Requirements

Conditions in this section of the permit (Section III. Facility-Wide or Generic Permit Requirements) apply to all emissions units located at the facility, including any units not specifically listed in Tables 1 and 2 of Section I.B.

[40 CFR § 71.6(a)(1).]

III.A. Permit Shield [40 CFR § 71.6(f)(3)]

(a) Nothing in this permit shall alter or affect the following:

(i) The liability of a permittee for any violation of applicable requirements prior to or at the time of permit issuance;

(ii) The ability of the EPA to obtain information under Section 114 of the Clean Air Act; or

(iii) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the Administrator under that section.

(b) Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements in effect as of the date of permit issuance provided that those requirements not applicable to the source are specifically identified and listed in the permit. The following requirements have been determined not to apply to this facility for the reasons specified:

(i) 40 CFR part 82, subpart H - There are no Halon fire extinguishers at this site.

(ii) 40 CFR part 60, subpart K - There are no petroleum liquid storage tanks at this site that were constructed, reconstructed, or modified prior to May 19, 1978.

(iii) 40 CFR part 60, subpart Ka - There are no petroleum liquid storage tanks at this site that were constructed, reconstructed, or modified between May 18, 1978 and June 23, 1984.

(iv) 40 CFR part 60, subpart LLL - There are no sweetening units or sulfur recovery units at this site.

(v) 40 CFR part 63, subpart HHH - There are no glycol dehydration units operating under SIC code 4922 at this site.

(vi) 40 CFR § 52.21 (PSD, in regard to the 1992 plant renovation only) - With the addition of emission units CG4, CG5, CG6, CG7, EG1, EG2, EG3, H1, T8365, and T17 during the 1992 plant renovation, the facility had a PTE of more than 250 tons per year for NOx and CO and became a Major Stationary Source. The potential emission increases associated with this renovation in 1992 were below the major source threshold levels, though, so this renovation did not trigger PSD requirements.

(vii) Compliance Assurance Monitoring (CAM) Rule - No equipment operates at the site with an emission control device.

III.B. <u>Emissions Trading and Operational Flexibility</u> [40 CFR § 71.6(a)(13)(i) through (iii), § 71.6(a)(8) and § 71.6(a)(10)]

(a) The permittee is allowed to make a limited class of changes under Section 502(b)(10) of the Clean Air Act within this permitted facility that contravene the specific terms of this permit without applying for a permit revision, provided the changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions) and are not title I modifications. This class of changes does not include:

(i) Changes that would violate applicable requirements; or

(ii) Changes that would contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

[40 CFR § 71.6(13)(i)]

(b) The permittee is required to send a notice to EPA at least 7 days in advance of any change made under this provision. The notice must describe the change, when it will occur and any change in emissions, and identify any permit terms or conditions made inapplicable as a result of the change. The permittee shall attach each notice to its copy of this permit.

[40 CFR § 71.6(13)(i)(A)]

(c) Any permit shield provided in this permit does not apply to changes made under this provision.

[40 CFR § 71.6(13)(i)(B)]

(d) No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes, for changes that are provided for in this permit.

[40 CFR § 71.6(a)(8)]

(i.e., RMP)

III.C. Chemical Accident Prevention [Clean Air Act Sections 112(r)(1), 112(r)(3), 112(r)(7) & 40 CFR part 68]

(a) A permittee of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR §68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR part 68 no later than the latest of the following dates:

(a) June 21, 1999; or

(ii) Three years after the date on which a regulated substance is first listed under 40 CFR § 68.130; or

(iii) The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR § 68.10(a)]

(b) This facility is subject to part 68 and shall certify compliance with all requirements of 40 CFR part 68, including the registration and submission of the RMP, as part of the annual compliance certification as required by 40 CFR part 71.

[40 CFR § 68.215(a)(ii)]

III.D. Stratospheric Ozone and Climate Protection [40 CFR part 82]

(a) The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR part 82, subpart F.

(i) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR §82.156.

(ii) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR §82.158.

(iii) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR §82.161.

(iv) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with recordkeeping requirements pursuant to 40 CFR §82.166(i). ("MVAC-like appliance" as defined at 40 CFR §82.152)

IV. <u>Part 71 Administrative Requirements</u>

IV.A. <u>Annual Fee Payment</u> [40 CFR §71.6(a)(7) and 40 CFR §71.9]

(a) The permittee shall pay an annual permit fee in accordance with the procedures outlined below.

[40 CFR § 71.9(a)]

(b) The permittee shall pay the annual permit fee each year no later than April 1.

[40 CFR § 71.9(h)]

(c) The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency.

[40 CFR § 71.9(k)(1)]

(d) The permittee shall send fee payment and a completed fee filing form to:

Mellon Bank
Attn: Part 71 Permit Accounting
Lockbox 360859
Pittsburgh, PA 15251-6859

[40 CFR § 71.9(k)(2)]

(e) The permittee shall send an updated fee calculation worksheet form and a photocopy of each fee payment check (or other confirmation of actual fee paid) submitted annually by the same deadline as required for fee payment to the address listed in Section IV.F. of this permit.

[40 CFR § 71.9(h)(1)]

(f) Basis for calculating annual fee:

(i) The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of all "regulated pollutants (for fee calculation)" emitted from the source by the presumptive emissions fee (in dollars/ton) in effect at the time of calculation.

[40 CFR § 71.9(c)(1)]

(1) "Actual emissions" means the actual rate of emissions in tpy of any regulated pollutant (for fee calculation) emitted from a part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year.

[40 CFR § 71.9(c)(6).]

(2) Actual emissions shall be computed using methods required by the permit for determining compliance, such as monitoring or source testing data.

[40 CFR § 71.9(h)(3)]

(3) If actual emissions cannot be determined using the compliance methods in the permit, the permittee shall use other federally recognized procedures.

[40 CFR § 71.9(e)(2)]

[The permittee should note that the presumptive fee amount is revised each calendar year to account for inflation, and it is available from EPA prior to the start of each calendar year.]

(ii) The permittee shall exclude the following emissions from the calculation of fees:

(1) The amount of actual emissions of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year;

[40 CFR § 71.9(c)(5)(i)]

(2) Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation; and

[40 CFR § 71.9(c)(5)(ii)]

(3) The quantity of actual emissions (for fee calculation) of insignificant activities [defined in § 71.5(c)(11)(i)] or of insignificant emissions levels from emissions units identified in the permittee's application pursuant to § 71.5(c)(11)(ii).

[40 CFR § 71.9(c)(5)(iii)]

(g) Fee calculation worksheets shall be certified as to truth, accuracy, and completeness by a responsible official. [Permittees should note that the fee calculation worksheet form already incorporates a section to help you meet this responsibility.]

[40 CFR § 71.9(h)(2)]

(h) The permittee shall retain fee calculation worksheets and other emissions-related data used to determine fee payment for 5 years following submittal of fee payment. [Emission-related data include, for example, emissions-related forms provided by EPA and used by the permittee for fee calculation purposes, emissions-related spreadsheets, and emissions-related data, such as records of emissions monitoring data and related support information required to be kept in accordance with § 71.6(a)(3)(ii).]

[40 CFR § 71.9(i)]

(i) Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with § 71.9(l).

[40 CFR § 71.9(l)]

(j) When notified by EPA of underpayment of fees, the permittee shall remit full payment within 30 days of receipt of notification.

[40 CFR § 71.9(j)(2)]

(k) A permittee who thinks an EPA assessed fee is in error and who wishes to challenge such fee, shall provide a written explanation of the alleged error to EPA along with full payment of the EPA assessed fee.

[40 CFR § 71.9(j)(3)]

IV.B. <u>Annual Emissions Inventory</u> [40 CFR § 71.9(h)(1)and (2)]

The permittee shall submit an annual emissions report of its actual emissions for both criteria pollutants and regulated HAPS for this facility for the preceding calendar year for fee assessment purposes. The annual emissions report shall be certified by a responsible official and shall be submitted each year to EPA on April 1.

The annual emissions report shall be submitted to EPA at the address listed in provision IV.F of this permit. [Permittees should note that an annual emissions report, required at the same time as the fee calculation worksheet by § 71.9(h), has been incorporated into the fee calculation worksheet form as a convenience.]

IV.C. <u>Compliance Requirements</u> [40 CFR § 71.6(a)(6)(i) and (ii), and sections 113(a) and 113(e)(1) of the Act, and § 51.212, § 52.12, § 52.33, § 60.11(g), and § 61.12.]

(a) The permittee must comply with all conditions of this part 71 permit. Any permit noncompliance constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

[40 CFR § 71.6(a)(6)(i)]

(b) It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

[40 CFR § 71.6(a)(6)(ii)]

(c) For the purpose of submitting compliance certifications in accordance with Section IV.D. of this permit, or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [Section 113(a) and 113(e)(1) of the Act, 40 CFR § 51.212, § 52.12, § 52.33, § 60.11(g), and § 61.12.]

IV.D. Compliance Certifications [40 CFR § 71.6(c)(5)]

The permittee shall submit to EPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices annually on April 1. The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with § 71.5(d).

[40 CFR § 71.6(c)(5)]

(a) The certification shall include the following:

(i) The identification of each permit term or condition that is the basis of the certification;

(ii) The identification of the method(s) or other means used for determining the compliance status of each term and condition during the certification period, and whether such methods or other means provide continuous or intermittent data. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

(iii) The status of compliance with each term and condition of the permit for the period covered by the certification based on the method or means designated in (ii) above. The certification shall identify each deviation and take it into account in the compliance certification;

(iv) Such other facts as the EPA may require to determine the compliance status of the source; and

(v) Whether compliance with each permit term was continuous or intermittent.
[40 CFR § 71.6(c)(5)(iii)]

IV.E. <u>Duty to Provide and Supplement Information</u> [40 CFR § 71.6(a)(6)(v), §71.5(a)(3), and § 71.5(b)]

(a) The permittee shall furnish to EPA, within a reasonable time, any information that EPA may request in writing to determine whether cause exists for modifying, revoking, and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the EPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR part 2, subpart B.
[40 CFR § 71.6(a)(6)(v), § 71.5(a)(3)]

(b) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. In addition, a permittee shall provide additional information as necessary to address any requirements that become applicable after the date a complete application is filed, but prior to release of a draft permit.
[40 CFR § 71.5(b)]

IV.F. <u>Submissions</u> [40 CFR § 71.5(d), § 71.6(c)(1) and § 71.9(h)(2)]

(a) Any document (application form, report, compliance certification, etc.) required to be submitted under this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) Any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to:

Part 71 Permit Contact
Air and Radiation Program, 8P-AR
U.S. Environmental Protection Agency,
999 18th Street, Suite 300
Denver, Colorado 80202-2466

IV.G. Severability Clause [40 CFR §71.6(a)(5)]

The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force.

IV.H. Permit Actions [40 CFR § 71.6(a)(6)(iii)]

This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

IV.I. Administrative Permit Amendments [40 CFR § 71.7(d)]

(a) The permittee may request the use of administrative permit amendment procedures for a permit revision that:

(i) Corrects typographical errors;

(ii) Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

(iii) Requires more frequent monitoring or reporting by the permittee;

(iv) Allows for a change in ownership or operational control of a source where the EPA determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the EPA;

(v) Incorporates into the part 71 permit the requirements from preconstruction review permits authorized under an EPA-approved program, provided that such a program meets procedural requirements substantially equivalent to the requirements of §§ 71.7 and 71.8 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in § 71.6; or

(vi) Incorporates any other type of change which EPA has determined to be similar to those listed above in subparagraphs (i) through (v) above. [Note to permittee: If subparagraphs (i) through (v) above do not apply, please contact EPA for a determination of similarity prior to submitting your request for an administrative permit amendment under this provision].

IV.J. Minor Permit Modifications [40 CFR § 71.7(e)(1)]

(a) The permittee may request the use of minor permit modification procedures only for those modifications that:

(i) Do not violate any applicable requirement;

(ii) Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

(iii) Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

(iv) Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

(1) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of title I; and

(2) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Clean Air Act;

(v) Are not modifications under any provision of title I of the Clean Air Act; and

(vi) Are not required to be processed as a significant modification.

[40 CFR § 71.7(e)(1)(i)(A)]

(b) Notwithstanding the list of changes ineligible for minor permit modification procedures in paragraph (a) above, minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA.

[40 CFR § 71.7(e)(1)(i)(B)]

(c) An application requesting the use of minor permit modification procedures shall meet the requirements of §71.5(c) and shall include the following:

(i) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

(ii) The source's suggested draft permit;

(iii) Certification by a responsible official, consistent with § 71.5(d), that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

(iv) Completed forms for the permitting authority to use to notify affected States as required under § 71.8.

[40 CFR § 71.7(e)(1)(ii)]

(d) The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by § 71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR § 71.7(e)(1)(v)]

(e) The permit shield under § 71.6(f) may not extend to minor permit modifications. [§ 71.7(e)(1)(vi)].

IV.K. <u>Group Processing of Minor Permit Modifications</u>. [40 CFR § 71.7(e)(2)]

(a) Group processing of modifications by EPA may be used only for those permit modifications:

(i) That meet the criteria for minor permit modification procedures under paragraphs IV.J. (a) of this permit; and

(ii) That collectively are below the threshold level of 10 percent of the emissions allowed by the permit for the emissions unit for which the change is requested, 20 percent of the applicable definition of major source in § 71.2, or 5 tons per year, whichever is least.

[40 CFR § 71.7(e)(2)(i)]

(b) An application requesting the use of group processing procedures shall be submitted to EPA, shall meet the requirements of §71.5(c), and shall include the following:

(i) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

(ii) The source's suggested draft permit;

(iii) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used;

(iv) A list of the source's other pending applications awaiting group processing, and a determination of whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under subparagraph (a)(ii) above; and

(v) Completed forms for the permitting authority to use to notify affected States as required under § 71.8.

[40 CFR § 71.7(e)(2)(ii)]

(c) The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by § 71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR § 71.7(e)(2)(v)]

(d) The permit shield under § 71.6(f) does not extend to group processing of minor permit modifications.

[§ 71.7(e)(1)(vi)]

IV.L. **<u>Significant Permit Modifications</u>** [40 CFR § 71.7(e)(3)]

(a) The permittee must request the use of significant permit modification procedures for those modifications that:

(i) Do not qualify as minor permit modifications or as administrative amendments;

(ii) Are significant changes in existing monitoring permit terms or conditions; or

(iii) Are relaxations of reporting or recordkeeping permit terms or conditions.

[40 CFR § 71.7(e)(3)(i)]

(b) Nothing herein shall be construed to preclude the permittee from making changes consistent with part 71 that would render existing permit compliance terms and conditions irrelevant.

[40 CFR § 71.7(e)(3)(i)]

(c) Permittees must meet all requirements of part 71 for applications, public participation, and review by affected states and tribes for significant permit modifications. For the application to be determined complete, the permittee must supply all information that is required by § 71.5(c) for permit issuance and renewal, but only that information that is related to the proposed change.

[40 CFR § 71.7(e)(3)(ii), § 71.8(d), & § 71.5(a)(2)]

IV.M. <u>Reopening for Cause</u> [40 CFR § 71.7(f)]

(a) The permit may be reopened and revised prior to expiration under any of the following circumstances:

(i) Additional applicable requirements under the Act become applicable to a major part 71 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended pursuant to § 71.7 (c)(3);

(ii) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

(iii) EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

(iv) EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

IV.N. <u>Property Rights</u> [40 CFR §71.6(a)(6)(iv)]

This permit does not convey any property rights of any sort, or any exclusive privilege.

IV.O. <u>Inspection and Entry</u> [40 CFR § 71.6(c)(2)]

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow EPA or an authorized representative to perform the following:

(a) Enter upon the permittee's premises where a part 71 source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

(d) As authorized by the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

IV.P. <u>Emergency Provisions</u> [40 CFR § 71.6(g)]

(a) In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

(i) An emergency occurred and that the permittee can identify the cause(s) of the emergency;

(ii) The permitted facility was at the time being properly operated;

(iii) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

(iv) The permittee submitted notice of the emergency to EPA within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements of Section II.F.(b) of this permit, concerning prompt notification of deviations.

(b) In any enforcement proceeding the permittee attempting to establish the occurrence of an emergency has the burden of proof.

(c) An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

IV.Q. **Transfer of Ownership or Operation** [40 CFR § 71.7(d)(1)(iv)]

A change in ownership or operational control of this facility may be treated as an administrative permit amendment if the EPA determines no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to EPA.

IV.R. **Off Permit Changes** [40 CFR §71.6(a)(12) and 40 CFR §71.6(a)(3)(ii)]

The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met, and that all records required by this section are kept on site at the source for a period of five years:

(a) Each change is not addressed or prohibited by this permit;

(b) Each change shall meet with all applicable requirements and shall not violate any existing permit term or condition;

(c) Changes under this provision may not include changes subject to any requirement of 40 CFR parts 72 through 78 or modifications under any provision of title I of the Clean Air Act;

(d) The permittee must provide contemporaneous written notice to EPA of each change, except for changes that qualify as insignificant activities under §71.5(c)(11). The written notice must describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

(e) The permit shield does not apply to changes made under this provision;

(f) The permittee must keep a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes; and

(g) For replacement of an existing permitted compressor engine or turbine with a new or overhauled engine or turbine of the same make, model, horsepower rating, or heat input capacity rating, and configured to operate in the same manner as the engine or turbine being replaced, in addition to satisfying all other provisions for Off-Permit Changes, the permittee satisfies the following provisions:

(i) the replacement engine or turbine employs air emissions control devices that are equivalent to those employed by the engine or turbine being replaced;

(ii) the replacement of the existing engine or turbine does not constitute a major modification or major new source as defined in Federal PSD regulations (40 CFR §52.21);

(iii) no new applicable requirements, as defined in 40 CFR §71.2, are triggered by the replacement; and

(iv) the following information is provided in a written notice to EPA, prior to installation of the replacement engine or turbine, in addition to the standard information listed above for contemporaneous written notices for off-permit changes:

(1) make, model number, serial number, horsepower rating and configuration of the existing engine or turbine and the replacement engine or turbine, and

(2) PSD applicability/non-applicability documentation, as follows:

Baseline = 2 yrs of past operation.

(A) if the existing source is a "major stationary source," as defined in 40 CFR §52.21(b)(1):

(1) for each pollutant regulated under the Act (except pollutants regulated under section 112(b) of the Act), for which the PTE of the replacement engine or turbine is "significant" as defined in 40 CFR §52.21(b)(23), a demonstration, including all calculations, that a significant net emissions increase has not occurred, when all source wide contemporaneous and creditable emission increases and decreases, as defined in 40 CFR §52.21, are summed with the PTE of the replacement engine or turbine.

(2) for each pollutant regulated under the Act (except pollutants regulated under section 112(b) of the Act), for which the PTE of the replacement engine or turbine is not "significant," documentation of the

calculations and methods that were used to reach that conclusion.

(B) if the existing source is not a "major stationary source," as defined in 40 CFR §52.21(b)(1), documentation with calculations to show that the PTE of the replacement engine or turbine, for each pollutant regulated under the Act (except pollutants listed in section 112(b) of the Act) is below the level defined as a major stationary source in 40 CFR §52.21(b)(1).

(3) PTE of the replacement engine or turbine shall be determined based on the definition of PTE in 40 CFR §52.21(b)(4). If multiple engines and/or turbines are being replaced, then the PTE used above shall be the aggregated PTE of all replacement engines and/or turbines.

Submittal of the written notice required above shall not constitute a waiver, exemption, or shield from applicability of any PSD permitting requirements under 40 §CFR 52.21 that would be triggered by the replacement of any one engine or turbine, or by replacement of multiple engines and/or turbines.

IV.S. <u>Permit Expiration and Renewal</u> [40 CFR §71.5(a)(1)(iii), §71.5(a)(2), §71.5(c)(5), §71.6(a)(11), §71.7(b), §71.7(c)(1), §71.7(c)(3)]

(a) This permit shall expire upon the earlier occurrence of the following events:

(i) For sources other than those identified in subparagraph (a)(i) above, five (5) years elapses from the date of issuance; or

(ii) The source is issued a part 70 or part 71 permit under an EPA approved or delegated permit program.

[40 CFR § 71.6(a)(11)]

(b) Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least 6 months but not more than 18 months prior to the date of expiration of this permit.

[40 CFR § 71.5(a)(1)(iii)]

(c) If the permittee submits a timely and complete permit application for renewal, consistent with § 71.5(a)(2), but EPA has failed to issue or deny the renewal permit, then all the terms and conditions of the permit, including any permit shield granted pursuant to § 71.6(f) shall remain in effect until the renewal permit has been issued or denied.

[40 CFR § 71.7(c)(3)]

(d) The permittee's failure to have a part 71 permit is not a violation of this part until EPA takes final action on the permit renewal application. This protection shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit any additional information identified as being needed to process the application by the deadline specified in writing by EPA.

[40 CFR § 71.7(b)]

(e) Renewal of this permit is subject to the same procedural requirements that apply to initial permit issuance, including those for public participation, affected State, and tribal review.

[40 CFR § 71.7(c)(1)]

(f) The application for renewal shall include the current permit number, description of permit revisions and off-permit changes that occurred during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form.

[40 CFR § 71.5(a)(2), §71.5(c)(5)]

V. Attachment to the Part 71 Permit

A. Permit Revision History

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER **	DESCRIPTION OF REVISION
None			

** In this column, identify the specific section and subsection where the revision has been included in the permit.

B. Inspection Information

1. Directions to Plant:

Beginning at Vernal, Utah, drive easterly on US 40 to the intersection with Highway 45. Travel south on Highway 45 for 20 miles. Turn right (west) at the CIG sign onto Wansutt Valley Road. Travel west on Wansutt Valley Road to the next CIG sign. Turn left at the sign and travel southwest on Glenn Bench Road for 19.5 miles to the Natural Buttes compressor station, which will be on the left side of the road.

2. Safety Equipment Required:

   Eye Protection, Hard Hat, Safety Shoes, Hearing Protection

Air Pollution Control
Title V Permit to Operate
Final Statement of Basis for Permit No. V-OU-0003-00.00
January 24, 2001

Colorado Interstate Gas Company
Natural Buttes Compressor Station
Uintah and Ouray Reservation
Uintah County, Utah

1. Facility Information

a. Location

Colorado Interstate Gas Company's Natural Buttes Compressor station is located in Uintah County in the northeast corner of the State of Utah, within the Uintah and Ouray Indian Reservation. It is located in the SW 1/4 of Section 24, T9S, R21E in Uintah County. The mailing address is:

Colorado Interstate Gas Company
P.O. Box 1087
Colorado Springs, CO 80944

b. Contacts

(1) The facility contact is:

Barry Schatz, Environmental Engineer
Colorado Interstate Gas Company
P.O. Box 1087
Colorado Springs, CO 80944

(2) The responsible official is:

William D. Stevens, Vice President
Colorado Interstate Gas Company
P.O. Box 1087
Colorado Springs, CO 80944

c. Description of operations

The Natural Buttes Compressor Station removes natural gas liquids (NGL's) from the wet gas stream the plant receives from production operations. Natural gas enters the facility from gathering lines and is fed to slug catchers to remove liquids. Collected liquids are stored in pressure vessels, and the remaining gas is fed to compressors driven by gas fired turbines. Natural gas discharged by the compressors is fed to an ethylene glycol dehydration unit. Ethyl glycol is introduced to the gas stream, which subsequently is chilled and fed to a three-phase separator. The compressors driven by natural gas fired reciprocating engines are utilized to provide propane refrigeration to cool the natural gas stream. Residue natural gas exiting the three-phase separator is transported off-site to a sales line, NGL collected from the three-phase separator is stored in pressure vessels, and rich ethylene glycol is sent to a regenerator. Heat is applied indirectly via heat medium oil to the regenerator to volatilize water from the rich glycol.

d. Permitting and/or construction history

The Natural Buttes Compressor Station was completed and phased in service in October, 1982. Additional equipment was installed in late 1992 as part of a plant renovation. EPA has no record of any federal permitting activity at this facility.

e. List of all units and emission-generating activities

Colorado Interstate Gas Company provided in its Natural Buttes Station application the information contained in Tables 1 and 2. Table 1 lists emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" are listed separately in Table 2.

Pursuant to Section II.B. of this permit titled "Alternative Operating Scenarios", Colorado Interstate Gas Company may replace any engine or turbine that is listed in Table 1 with a new or overhauled engine or turbine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine or turbine being replaced, if all the provisions of Section IV.R. titled "Off-Permit Changes" are met.

Part 71 allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tons/year for all regulated pollutants that are not listed as hazardous air pollutants ("HAP") under Section112(b) and below 1000 lbs/year or the de minimis level established under Section 112(g), whichever is lower, for HAPs. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee. Units that qualify as "insignificant" for the purposes of the part 71 application are in no way exempt from applicable requirements or any requirements of the part 71 permit.

Pursuant to Section IV.R. of this permit titled "Off Permit Changes", modifications to insignificant activities emission sources can be made as long as it can be documented by Colorado Interstate Gas Company that the change is insignificant without notifying EPA or reopening the part 71 permit.

Colorado Interstate Gas Company stated in its Natural Buttes Compressor Station application that the emission units in Table 2 below qualified for the emission threshold exemption.

Table 1 - Emission Units
Colorado Interstate Gas Company Natural Buttes Compressor Station

Emission Unit Id.	Description	1. Installation Date 2. Maximum design heat input 3. Fuel type 4. Use	Control Equipment
CG01, CG02	2 - Superior 8G825 Engines Serial Nos. 292039, 292029	1. October, 1982 2. 5.8 Million Btu/hr each 3. Natural Gas 4. Compressor Driver	None
CG04, CG05, CG06, CG07	4 - Allison 501-KC5 Gas Turbines Serial Nos. ASP-1477, ASP-1471, ASP-1464, ASP-1467	1. November, 1992 2. 35.4 Million Btu/hr each 3. Natural Gas 4. Compressor Driver	None
EG1, EG2, EG3	3 - Caterpillar 3512 LE Engines Serial Nos. 4KC00323, 4KC00324, 4KC00326	1. November, 1992 2. 6.1 Million Btu/hr each 3. Natural Gas 4. Electric Generator Driver	None
H1	Heatec Hot Oil Heater	1. 2000 2. 6.67 Million Btu/hr 3. Natural Gas 4. Process Heater	None
T8365	Propak Custom Skid Dehydration Unit Still	1. November, 1992 2. N/A 3. Natural Gas 4. Ethylene Glycol Regeneration	Condenser
T17	300 barrel atmospheric storage tank	1. December, 1992 2. N/A 3. N/A 4. Pigging liquids storage/loadout	None
Fug	Piping components	1. 1981-1992 2. N/A 3. N/A 4. Fugitive Equipment Leaks (Plant-Wide)	None

Table 2 - Insignificant Emission Units
Colorado Interstate Gas Company Natural Buttes Compressor Station

Emission Unit Id. No.	Description
1	T1 - 240 bbl. triethylene glycol storage tank
2	T2 - 240 bbl. Methanol storage tank
3	T3 - 6,875 gallon lubricating oil storage tank
4	T5 - 250 bbl. Unleaded gasoline storage tank
5	T7 - 1250 gallon septic tank
6	T10 - 7140 gallon slop tank
7	T11 - 1250 gallon septic tank
8	T12 - 700 gallon ambitrol storage tank
9	T13 - 700 gallon lubricating oil storage tank
10	T14 - 700 gallon used oil storage tank
11	T15 - 700 gallon ethylene glycol storage tank
12	T16 - 100 gallon lubricating oil day tank
13	T18 - 6300 gallon used oil storage tank
14	500 gallon diesel storage tank
15	1200 gallon ambitrol storage tank
16	V19 - Blowdown vessel vent
17	T8 - Water tank
18	T6 - Abandoned water tank
19	V1, V2, V3, V4 - Pressure vessels

f. Potential to emit

Table 3 includes potential to emit data provided by the Colorado Interstate Gas Company for the Natural Buttes Compressor Station. Potential to emit means the maximum capacity of the Colorado Interstate Gas Company Natural Buttes Compressor Station to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the Colorado Interstate Gas Company Natural Buttes Compressor Station to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, may be treated as part of its design if the limitation is enforceable by EPA. Potential to emit is meant to be a worse case emissions calculation. Actual emissions may be much lower.

In their application for the Natural Buttes Compressor Station, Colorado Interstate Gas Company speciated VOC emissions into the respective hazardous air pollutants (HAPs). This information has been provided in Table 4.

Colorado Interstate Gas Company must also submit annual estimates of *actual* emissions from the Natural Buttes Compressor Station for all regulated pollutants as part of the requirement to pay an annual fee. EPA will review these submittals for accuracy.

Table 3 - Potential to Emit in Tons per Year
Colorado Interstate Gas Company Natural Buttes Compressor Station

Emission Unit Id.	Regulated Air Pollutants						
	NOx (tons/yr)	VOC (tons/yr)	SO2 (tons/yr)	PM10 (tons/yr)	CO (tons/yr)	Lead (tons/yr)	HAP (tons/yr)
CG1	95.2	6.3	0	0	63.5	0	0.6
CG2	95.2	6.3	0	0	63.5	0	0.6
CG4	51.0	14.8	0	0	33.6	0	1.7
CG5	51.0	14.8	0	0	33.6	0	1.7
CG6	51.0	14.8	0	0	33.6	0	1.7
CG7	51.0	14.8	0	0	33.6	0	1.7
EG1	11.7	5.8	0	0	18.0	0	2.0
EG2	11.7	5.8	0	0	18.0	0	2.0
EG3	11.7	5.8	0	0	18.0	0	2.0
H1	3.3	0.2	0	0	2.8	0	0
T8365	0	33.6	0	0	0	0	17.8
T17	0	34.9	0	0	0	0	1.9
Fug	0	19.4	0	0	0	0	0
TOTAL	432.8	177.3	0	0	318.2	0	33.7

NO_x - oxides of nitrogen   VOC - volatile organic compounds
SO_2 - sulfur dioxide PM_{10} - particulate matter with a diameter 10 microns or less
CO - carbon monoxide   HAP - hazardous air pollutants (see Clean Air Act Section 112(b))

Table 4 -- Hazardous Air Pollutant Potential Emission
Colorado Interstate Gas Company Natural Buttes Compressor Station

Emission Unit Id.	Hazardous Air Pollutant (in tons per year)					
	Formaldehyde	Benzene	Toluene	Ethyl Benzene	Xylene	N-Hexane
CG1	0.6	0	0	0	0	0
CG2	0.6	0	0	0	0	0
CG4	1.7	0	0	0	0	0
CG5	1.7	0	0	0	0	0
CG6	1.7	0	0	0	0	0
CG7	1.7	0	0	0	0	0
EG1	2.0	0	0	0	0	0
EG2	2.0	0	0	0	0	0
EG3	2.0	0	0	0	0	0
H1	0	0	0	0	0	0
T8365	0	11.6	4.0	0.6	0.9	0.7
T17	0	0.2	0.5	0	0.1	1.1
Fug	0	0	0	0	0	0
TOTAL	14.0	11.8	4.5	0.6	1.0	1.8

2. Tribe Information

a. Indian country:

Colorado Interstate Gas Company Natural Buttes Compressor Station is located within the exterior boundaries of the Uintah and Ouray Indian Reservation.

b. The reservation:

The Uintah and Ouray Reservation consists of two separate but contiguous tracts of land set aside in the nineteenth century for the exclusive use and occupancy of the three bands of Indians (Uncompahgre, Uintah and Whiteriver) who comprise the present-day Ute Indian Tribe. The Uintah Valley Reservation along the Duchesne River was established in 1861 and confirmed by Congress in the Act of May 5, 1864. An Executive Order, dated January 5, 1882, established the Uncompahgre Reservation for the use and occupancy of the Uncompahgre Utes. This

Reservation was comprised of a large rectangular area of uninhabited and largely uninhabitable land in eastern Utah bordering on Colorado's western boundary.

In the *Ute Tribe V* decision, the Tenth Circuit Court of Appeals excluded from "Indian country" those lands within the original Uintah Valley Reservation boundaries that were unallotted and opened to non-Indian settlement under the 1902-1905 legislation. Therefore, the original Uintah and Ouray Reservation is diminished.

c. Tribal government:

The Ute Tribe is a constitutional government organized pursuant to the authority of section 16 of the Indian Reorganization Act of June 16, 1934, 48 Stat. 986. The Tribe adopted its Constitution and By-Laws on December 19, 1936, for the government, protection and common welfare of the Ute Indian Tribe and its members. It was approved by the Secretary of the Interior on January 19, 1937.

The governing body of the Ute Tribe consists of six individuals who are elected to the Ute Tribal Business Committee. Members of the Business Committee are elected by band: two representatives each from the Uncompahgre, Uintah and Whiteriver Bands. Members are elected for a term of four years by the eligible members of the respective bands. The Business Committee is responsible for the overall social, economic and natural resource development of the Reservation and for the members of the Ute Tribe. They are delegated broad powers under the Tribe's Constitution to carry out these responsibilities. The Tribe also operates an extensive tribal court system, including a lower court, a court of appeals, and a juvenile court.

d. Local air quality and attainment status:

The Uintah and Ouray Indian Reservation, either attains the national ambient air quality standard for all criteria pollutants or is "unclassified." An area is unclassifiable when there is insufficient monitoring data. As of December 1999, the Ute Indian Tribe maintained an air monitoring network to collect total suspended particulate (TSP) data at its Myton station and its Whiterocks station. The TSP sampler at the Whiterocks station is now being modified to sample for PM_{10} data. Both stations have been reporting daily and annual averages of TSP concentrations.

3. Applicable Requirements

a. The following federally applicable requirements have been considered for applicability:

Chemical Accident Prevention Program

Based on Colorado Interstate Gas Company's application, the Natural Buttes Compressor Station currently has regulated substances above the threshold quantities in this rule and therefore is subject to the requirement to develop and submit a risk management plan. CIG has stated in their application that the risk management plan has been registered with EPA.

Stratospheric Ozone and Climate Protection

Colorado Interstate Gas Company's Natural Buttes Compressor Station has an air conditioning system installed in the facility's main control building, and two window air conditioning units on site, one in the chromatograph building, and the other in the personnel building. These systems are charged with R-22 refrigerant. Colorado Interstate Gas Company must comply with the standards of 40 CFR § 82, subpart F for recycling and emissions reduction, if it services, maintains, or repairs the air conditioning unit in any way or if it disposes of the unit. Specifically, Colorado Interstate Gas Company must comply with 40 CFR §§ 82.156, 82.158, 82.161 and 82.166(i).

Based on information supplied by the applicant, there are no Halon fire extinguishers at the Natural Buttes Compressor Station. However, should the Colorado Interstate Gas Company obtain any Halon fire extinguishers, then it must comply with the standards of 40 CFR § 82, subpart H for Halon emissions reduction, if it services, maintains, tests, repairs, or disposes of equipment that contains halons or uses such equipment during technician training. Specifically, Colorado Interstate Gas Company would be required to comply with Title VI of the Clean Air Act and submit an application for a modification to this Title V permit.

New Source Performance Standards (NSPS)

40 CFR Part 60, Subpart A: General Provisions. This subpart applies to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in part 60. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 60.

The Colorado Interstate Gas Company Natural Buttes Compressor Station is subject to the provisions of 40 CFR part 60, subparts Kb, GG, and KKK. Therefore, the general provisions of 40 CFR part 60 do apply.

40 CFR Part 60, Subpart K: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. 40 CFR part 60, subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

The Colorado Interstate Gas Company Natural Buttes Compressor Station has no storage vessels for petroleum liquids at this site which were constructed, reconstructed, or modified prior to May 19, 1978. Therefore, this rule does not apply.

40 CFR Part 60, Subpart Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

The Colorado Interstate Gas Company Natural Buttes Compressor Station has no storage vessels greater than 40,000 gallons which were constructed, reconstructed or modified between May 18, 1978 and June 23, 1984. Therefore, this rule does not apply.

40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 40 cubic meters.

The Colorado Interstate Gas Company Natural Buttes Compressor Station has three product storage vessels, T-17, V-13, and V-14 which have a capacity greater than 40 cubic meters and which were constructed after July 23, 1984. The applicant has stated that emission unit NGLV (pressure vessels V-13 and V-14, NGL product storage vents) is no longer a source and is exempt from this rule because it is designed to operate in excess of 204.9 kPa and without emissions to the atmosphere (see 40 CFR 60.110b(d)(2)) . The applicant has stated that the pressure vessel regulators which previously opened at 150 psi and vented to the atmosphere were replaced with regulators that open at 200 psi. Vapors from these regulators are now piped into pressure vessels V-1,2,3,4. A recompressor controls vapors from these vessels. From the recompressor the vapors go into fuel gas that is burned at the plant or into the pipeline gas stream. This system, according to the applicant, eliminates venting from any of the pressure vessels to the atmosphere. Therefore, this rule applies only to T-17.

40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. This rule applies to stationary gas turbines, with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hr), that commenced construction, modification, or reconstruction after October 3, 1977. Specifically, units CG4, CG5, CG6, and CG7 have heat input rates greater than 10.7 gigajoules per hour and were installed in 1992. They are affected units and are therefore subject to this rule.

A custom fuel sampling schedule has been approved for the permittee under subpart GG. This custom schedule requires that records be kept for a period of three years. In order to be consistent with the recordkeeping requirements of part 71 which requires that records be kept for a period of five years, the recordkeeping requirement of the custom fuel sampling schedule has been changed to five years.

40 CFR Part 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. Natural gas liquids are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

The Colorado Interstate Gas Company Natural Buttes Compressor Station does extract natural gas liquids from field gas and therefore does meet the definition of a natural gas processing plant under this subpart. The natural gas liquid extraction plant was constructed after January 20, 1984, the effective date of this regulation. Therefore, this rule does apply.

40 CFR Part 60, Subpart LLL: Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

The Colorado Interstate Gas Company Natural Buttes Compressor Station does not perform sweetening or sulfur recovery at the facility. Therefore, this rule does not apply.

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

400 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for hazardous air pollutants (HAP) that regulate specific categories of sources that emit one or more HAP regulated pollutants under the Clean Air Act. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 63.

The Colorado Interstate Gas Company Natural Buttes Compressor Station is subject to 40 CFR part 63, subpart HH. The glycol dehydration unit, T8365, is an affected unit. Therefore, the general provisions of 40 CFR part 63 do apply.

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This rule applies to the owners and operators of affected units located at natural gas production facilities that are major sources

of hazardous air pollutants (HAPs), and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions, and the group of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

The facility is a natural gas processing facility. All HAP emission points at the site are considered in the determination of a major source. Based on this, the facility is a major HAP source, and this rule does apply to The Colorado Interstate Gas Company Natural Buttes Compressor Station. Specifically, this rule applies to each of the following affected sources: each glycol dehydration unit; each storage vessel with the potential for flash emissions; the group of all ancillary equipment, except compressors, intended to operate in volatile hazardous air pollutant service; and compressors intended to operate in volatile hazardous air pollutant (VHAP) service which are located at natural gas processing plants. The glycol dehydration unit, T8365 is subject to this rule.

Storage vessel T-17 has the potential for flash emissions, however based on information submitted by the applicant, the tank has an actual annual average hydrocarbon liquid throughput of less than 500 barrels per day (79,500 liters per day), and therefore is not subject to the rule (see definition of "storage vessel with the potential for flash emissions" in the rule).

Compressor engines CG1 through CG7 are potentially subject to this rule if they are operated in VHAP service. The applicant has stated however, that compressor engines CG1 and CG2 are in propane service, and that propane is not a VHAP. The applicant has further stated that compressor engines CG4 through CG7 compress inlet gas, and that the sample analysis of the inlet gas shows that it does not contain VHAP equal to or greater than 10%. The requirements of §63.772(a) say that compressors are presumed to be in VHAP service unless an owner or operator demonstrates that the piece of equipment is not in VHAP service. For the purposes of determining the VHAP content of the process fluid that is contained in or contacts a compressor, Method 18 of 40 CFR part 60, appendix A, shall be used. The applicant has submitted two recent (December 1999 and July 2000) analyses of inlet gas from Natural Buttes which indicate that the VHAP is less than 10%. Based on the analyses supplied by the applicant, the compressor engines CG1 through CG7 are not subject to this rule.

<u>40 CFR Part 63, Subpart HHH</u>: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This rule applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are major source of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines used

for long distance transport and storage vessel is a tank or other vessel designed to contain an accumulation a crude oil, condensate, intermediate hydrocarbon, liquids, produced water or other liquid and is constructed of wood, concrete, steel or plastic structural support.

This rule does not apply to The Colorado Interstate Gas Company Natural Buttes Compressor Station because the affected source under the rule is each glycol dehydration unit, and there are no glycol dehydration units operating under SIC code 4922 at this site. Please note that there is a glycol dehydration unit at this site, but that it operates under SIC code 1321 and is reviewed for Subpart HH above.

Prevention of Significant Deterioration (PSD):

A review of Colorado Interstate Gas Company Natural Buttes Compressor Station's application shows that with the renovation of the plant that occurred in 1992 (addition of emission units CG4, CG5, CG6, CG7, EG1, EG2, EG3, H1, T8365, and T17) the facility had a potential to emit of more than 250 tons per year for NOx and CO and is therefore considered a Major Stationary Source under 40 CFR 52.21. The potential emission increases of any pollutant regulated under the Clean Air Act [not including pollutants listed under Section 112] associated with the renovation of the plant that occurred in 1992 were below the major source threshold levels, therefore, this renovation was not required to obtain a PSD permit.

Compliance Assurance Monitoring (CAM) Rule

The CAM rule applies to each Pollutant Specific Emission Unit (PSEU) that meets a three-part test. The PSEU must be 1) subject to an emission limitation or standard, and 2) use an add-on control device to achieve compliance, and 3) have pre-control emissions that exceed or are equivalent to the Title V, 100 tpy major source threshold.

The applicant has stated that no equipment currently operates at the Natural Buttes facility with an emission control device. Therefore, no unit at this facility is subject to the CAM requirements.

Periodic Monitoring

The monitoring requirements contained in 40 CFR part 60, subpart GG only require a one time performance test for NOx to be conducted to show initial compliance with the requirements of section 60.332. Therefore, in accordance with 40 CFR Section 71.6(a)(3)(i), in order to assure compliance with this requirement throughout the term of this permit, the applicant shall conduct quarterly monitoring of the turbines (units CG4, CG5, CG6, CG7) with a portable analyzer.

b. Conclusion

Based on the information provided in Colorado Interstate Gas Company's application for the Natural Buttes Compressor Station, EPA has no evidence that this source is subject to any existing applicable federal CAA programs except those discussed in 3.a. above. Further, the Colorado Interstate Gas Company Natural Buttes Compressor Station is not subject to any implementation plan such as exist within state jurisdictions. Therefore, except for the chemical accident prevention program rule, periodic monitoring, the stratospheric ozone and climate protection rule, the requirements of 40 CFR part 60, subparts A, Kb, GG, and KKK, and the requirements of 40 CFR part 63, subparts A and HH, the Natural Buttes Compressor Station is not subject to any other substantive requirements that control their emissions under the CAA.

EPA recognizes that, in some cases, sources of air pollution located in Indian country are subject to fewer requirements than similar sources located on land under the jurisdiction of a state or local air pollution control agency. To address this regulatory gap, EPA is in the process of developing national regulatory programs for preconstruction review of major sources in nonattainment areas and of minor sources in both attainment and nonattainment areas. These programs will establish, where appropriate, control requirements for sources that would be incorporated into part 71 permits. To establish additional applicable, federally-enforceable emission limits, EPA Regional Offices will, as necessary and appropriate, promulgate Federal Implementation Plans (FIPs) that will establish Federal requirements for sources in specific areas. EPA will establish priorities for its direct Federal implementation activities by addressing as its highest priority the most serious threats to public health and the environment in Indian country that are not otherwise being adequately addressed. Further, EPA encourages and will work closely with all tribes wishing to develop Tribal Implementation Plans (TIPs) for approval under the Tribal Authority Rule. EPA intends that its federal regulations created through a FIP will apply only in those situations in which a tribe does not have an approved TIP.

4. EPA Authority

a. General authority to issue part 71 permits

Title V of the Clean Air Act requires that EPA promulgate, administer, and enforce a Federal operating permits program when a state does not submit an approvable program within the time frame set by title V or does not adequately administer and enforce its EPA-approved program. On July 1, 1996 (61 FR 34202), EPA adopted regulations codified at 40 CFR 71 setting forth the procedures and terms under which the Agency would administer a Federal operating permits program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing Federal operating permits to covered stationary sources in Indian country.

As described in 40 CFR 71.4(a), EPA will implement a part 71 program in areas where a state, local, or tribal agency has not developed an approved part 70 program. Unlike states, Indian tribes are not required to develop operating permits programs, though EPA encourages tribes to do so. See, e.g., Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the "Tribal Authority Rule"). Therefore, within Indian country, EPA believes it is generally appropriate that EPA administer and enforce a part 71 federal operating permits program for stationary sources until tribes receive approval to administer their own operating permits programs.

5. Use of All Credible Evidence

Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source and EPA in such determinations.

6. Public participation

a. Public notice

As described in 40 CFR 71.11(a)(5), all part 71 draft operating permits shall be publicly noticed and made available for public comment. The public notice of permit actions and public comment period is described in 40 CFR 71(d).

There will be a 30 day public comment period for actions pertaining to a draft permit. Public notice has been given for this draft permit by mailing a copy of the notice to the permit applicant, the affected state, tribal and local air pollution control agencies, the city and county executives, the state and federal land managers and the local emergency planning authorities which have jurisdiction over the area where the source is located. A copy of the notice has also been provided to all persons who have submitted a written request to be included on the mailing list. If you would like to be added to our mailing list to be informed of future actions on these or other Clean Air Act permits issued in Indian country, please send your name and address to the address listed below:

Dennis M. Myers, Part 71 Permit Contact
U.S. Environmental Protection Agency, Region 8
999 18th Street, Suite 300 (8P-AR)
Denver, Colorado 80202-2466

Public notice was published in the Uintah Basin Standard on November 14, 2000, giving opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for comment

Members of the public were given the opportunity to review a copy of the draft permit prepared by EPA, the application, this statement of basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents were made available at:

Uintah County Clerk's Office
147 East Main Street, Suite 2300
Vernal, Utah 84078

Uintah & Ouray Indian Tribe
Environmental Programs Office
6358 East Highway 40
Fort Duchesne, Utah 84026

U.S. EPA Region VIII
Air and Radiation Program Office
999 18th Street, Suite 300 (8P-AR)
Denver, Colorado 80202-2466

The only comments received by EPA during the public comment period were from the applicant.

c. Opportunity to request a hearing

During the public comment period which ended on December 13, 2000, a person could submit a written request for a public hearing to the part 71 Permit Contact, at the address listed in section 6.a above, by stating the nature of the issues to be raised at the public hearing. No requests for a public hearing were received by EPA.

d. Appeal of permits

Within 30 days after the issuance of a final permit decision, any person who filed comment on the draft permit or participated in the public hearing may petition to the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or participate in the public hearing may petition for administrative review only if the changes from the draft to the final permit decision or other new grounds that were not reasonably foreseeable during the public comment period. The 30 day period to appeal a permit begins with EPA's service of the notice.

The petition to appeal a permit must include a statement of the reasons supporting the review, a demonstration that any issues were raised during the public comment period or a demonstration that it was impracticable to raise the objections within the public comment period, or the grounds for such objections arose after such a period and when appropriate a showing that the condition in question is based on a finding of fact or conclusion of law which is clearly erroneous, or an exercise of discretion or an important policy consideration which the Environmental Appeals Board should review.

The Environmental Appeals Board will issue an order either granting or denying the petition for review, within a reasonable time following the filing of the petition. The public notice shall establish a briefing schedule for the appeal and state that any interested person may file an amicus brief. Notice of denial of review will be sent only to the permit applicant and to the person requesting the review.

A motion to reconsider a final order shall be filed within 10 days after the service of the final order. Every motion must set forth the matters claimed to have been erroneously decided and the nature of the alleged errors. Motions for reconsideration shall be directed to the Administrator rather than the Environmental Appeals Board. A motion for reconsideration shall not stay the effective date of the final order unless it is specifically ordered by the Board.

e. Petition to reopen a permit for cause

Any interested person may petition EPA to reopen a permit for cause, and the EPA may commence a permit reopening on its own initiative. EPA shall not revise, revoke, and reissue or terminate a permit except for reasons specified in 40 CFR 71.7(f) or 71.6(a)(6)(i). All requests shall be in writing and shall contain facts or reasons supporting the request. If EPA decides the request is not justified, it will send the requester a brief written response giving a reason for the decision. Denial of these requests are not subject to the public notice comment or hearings. Denials can be informally appealed to the Environmental Appeals Board.

f. Notice to affected states/tribes

As described in 40 CFR 71.11(d)(3)(i), public notice was given by mailing a copy of the notice to the air pollution control agencies of affected states, tribal and local air pollution control agencies which have jurisdiction over the area in which the source is located, the chief executives of the city and county where the source is located, any comprehensive regional land use planning agency and any state or federal land manager whose lands may be affected by emissions from the source. The following entities were notified:

State of Colorado, Department of Health
State of Utah, Environment Department
State of Wyoming, Department of Environmental Quality
Ute Indian Tribe, Environmental Programs Office

Uintah County, County Clerk
National Park Service, Air, Denver, CO
U.S. Department of Agriculture, Forest Service, Rocky Mountain Region
Town of Vernal, Mayor